INSTRUMENTING BUILDINGS TO DETERMINE RETROFIT SAVINGS: MURPHY'S LAW STRIKES AGAIN

Dennis L. O'Neal John Bryant Kim Carlson
Energy Systems Laboratory
Department of Mechanical Engineering,
Texas A&M University, College Station, TX

ABSTRACT

Experiences with instrumentation, installation and maintenance of building energy metering systems are presented. The building energy metering was installed in a variety of locations in programs handled by the Energy Systems Laboratory at Texas A&M University. Metering typically includes monitoring for the whole-building electric load, chilled and hot water thermal loads and selected submetered electrical loads. The emphasis of the lessons learned was on the instrumentation used and installation and maintenance problems encountered during the course of the metering projects.

INTRODUCTION

During the past eight years, the Energy Systems Laboratory (ESL) has installed energy monitoring equipment in over 250 buildings (2500 channels). Locations of these buildings range from severe Southern climates like Texas and Florida to Northern climates like Minnesota. The monitoring equipment provides data to support building energy analysis and the measurement of energy savings from energy conservation measures implemented in the candidate building(s). The installed equipment has typically included thermal metering (chilled and hot water Btu), electrical load metering (kW), psychrometric data (cooling and heating supply air temperatures and relative humidities), and weather monitoring (solar radiation, wind speed, ambient air relative humidity, and ambient air dry bulb temperature).

This paper summarizes some of the more important experiences related to building energy metering instrumentation and installation. The paper builds upon two previous papers (O'Neal, et al. [1992,1993]) on problems related to installation and maintenance of energy metering equipment. Even though it has been five years since the previous paper was published, there has been little published in the open literature on this topic in this interim. Therefore, it is important that lessons learned on the ESL project be noted and shared with others who endeavor to undertake similar projects. The knowledge shared could potentially allow major savings in manpower and costs in future projects.

If energy monitoring is being conducted to evaluate the potential savings due to a planned energy conservation retrofit measure (ECRM), then prompt installation of energy metering equipment can provide the analyst with a wealth of energy usage data. Many of the lessons described can provide the reader with information that should help speed the installation of a metering project. Some of the identified problems may seem so obvious that "anyone who is careful" should be able to avoid them. However, even experienced installers of building energy metering systems seem to struggle with some of these "obvious" problems. If a solution is developed, often there is no written record left for future reference.

This paper is meant primarily to be a discussion of instrumentation and installation problems. There are a number of "real world" problems that involve proper communication between the installer and facilities personnel, installer and manufacturer or between the installer and those who have to analyze the data. This paper includes three categories of problems: (1) Equipment, (2) Installation, and (3) Maintenance.

EQUIPMENT

To have a meaningful analysis of energy use data on buildings, it is critical that the instrumentation be reliable and provide accurate information on what is being measured. Unfortunately, instrumentation can provide a stream of numbers that may not reflect what is actually being measured. The equipment problems were divided into thermal metering, electrical measurement, and psychrometric measurements.

Thermal Metering

Thermal metering is important for large commercial building applications where the building is purchasing chilled water, hot water, or steam. In addition, thermal metering may be applied where the user wants to track the efficiency of a chiller or a boiler. Thermal metering typically involves monitoring entering and leaving temperatures of the water and the water flow rate. The signals from the flowmeters and temperatures sensors are supplied to a thermal energy meter, which applies appropriate conversion factors and fluid properties to obtain the thermal energy usage. For our installations, some of the sites had existing flowmeters and temperature sensors, while for others, it was necessary to install the required transducers into piping while the systems were operating. Some of the primary problems with thermal metering have included:

1. A $2500 flow meter may not provide any more accurate flow measurement than a $600 flow meter. Throughout the monitoring projects, at least six different types of flowmeters have been used. These have included insertion paddlewheel, insertion turbine, ultra-sonic, venturi, stainless steel target, and pitot static type flowmeters. With the exception of the venturi flowmeter, all of these different types of flowmeters have been tested at the flow calibration facility at the Energy Systems Laboratory. While the different flowmeters may have slightly different flow ranges, for typical applications in the 3 to 10 ft/s range in chilled and hot water piping systems, they all gave measurements within ±2%. In some instances, the manufacturer's flow constant had to be adjusted after calibration at the ESL flow facility. However, in most applications, the more expensive flowmeters did not appear to provide any significant advantage over the less expensive flow meters in terms of performance under standard pipe flows.

2. If the sales literature on a flowmeter says it can perform at less than one feet/second, treat it with a healthy dose of skepticism._ As stated above, one normally expects the flowrate in a chilled or hot water piping system to vary between 3 to 10 feet/second. However, due to oversizing of the piping system and retrofits with variable speed pumping, we have seen many systems where the flow rates have been less than 1 foot/second. We have termed these "low flow" conditions. Under these conditions, if the flowmeter still functions, it may be off as much as ±20 to ±40%. Some flowmeters do not produce any signal at these conditions. Unfortunately, for many retrofit metering applications where there is no existing metering, so it is difficult to know what the flow conditions are in the pipe before the flowmeter is installed.

3. A thermal energy meter that is not field scaleable will be set wrong at the factory. The initial brands of thermal energy meters utilized had to be set for a specific application at the factory. Information was provided to the factory on the type of flow meter, anticipated temperature difference, pipe size, maximum estimated energy, etc. The factory would then "burn-in" a ROM for that particular application or install other hardware for that specific application. Often the estimate provided by the facilities personnel at a given site for the energy rate of the chilled or hot water line was off by an order of magnitude. Likewise, these personnel had only estimates of the pipe sizes and these were often wrong. There also were several meters delivered from the factory that had been incorrectly programmed. The net result was that the meters provided were not appropriate for the particular application, and could not be changed in the field once it was determined that the meter was incorrect. It was not unusual for the manufacturer of the thermal energy meter to estimate that it would take four to six weeks to reprogram the meter, which cause serious gaps in the pre-retrofit data.

Electrical Metering

For many building energy metering applications, electrical measurements are the only measurements made. For this project, the decision is often based on funds available for the metering installation and on the retrofits being installed in the building. Typically, these measurements include whole-building electric feeds, motor control center feeds, individual motor loads' chiller feeds, and lighting loads. Experiences with electrical measurements have included:

1. The marked polarity of current transformers (CTs)will be the opposite of its actual polarity. The polarity of CTs should be checked before installation. On a single-phase application, a CT with a reverse polarity may be a nuisance (you'll get negative power). However, on a three-phase application, one CT with reverse polarity will cause major errors in the measured total power of the equipment that may not be detected without hand verification of the load. For instance, in

one application, a CT with reversed polarity was found on a 30 kW three-phase variable speed motor. The CTs had been installed according to the manufacturer's instructions (i.e., with the arrow pointing toward the line source). The indicated power of the motor was 1.5 kW, which did not make sense because the size of the motor and the fact that it was running at 82% of its maximum speed. A close check of one of the CTS used to monitor the equipment revealed that the polarity was marked incorrectly. Switching the leads to the CT corrected the problem even though the markings of the CT wires were now reversed.

2. The output of a current transformer will be far different from its rating. Much of the data acquisition equipment used in the monitoring studies utilizes a current transformer that produces a 333 mVAC output at rated full load. Voltages of 3 and 10 Volts from some CTs that were clearly marked 333 mV output have been observed. An input of 10 VAC instead of 333 mVAC to the data logging equipment has produced some unusual readings from the power channels in the data loggers and could possibly damage some loggers. One symptom was that the power signals for a fan load slowly decayed over time. The net result was that the bad CT not only affected the channel to which it was connected, but all power readings from that particular logger. These problems have led to the development of procedures to pre-check the polarity and output of CT's before being installed.

3. Metering with an existing Energy Management and Control System (EMCS) appears attractive, but bottom line costs may be prohibitive and performance may not meet manufacturer's claims. Much of the instrumentation required to monitor energy use in building systems may already be present as part of the EMCS. Sometimes the signals from this equipment can be shared by both the EMCS system and a separate dedicated logger for recording energy use. Another option is to use the EMCS data trending features to record the data. Our approach generally has been to share electrical signals when possible and share thermal signals only if required by the facility. The advantage with electrical sharing is reduced installation costs and isolation from the EMCS. EMCS shutdowns due to maintenance, reprogramming, and unknowledgeable operators usually do not affect the signal to our data logger. The main disadvantages to sharing signals are: 1) poor documentation of the existing EMCS, 2) difficulty of tracing wires (usually in conduit), 3) difficulty integrating metering systems and 4) determining responsibility for repairs and calibration.

The responsibility for repairs and calibration is an issue of great importance. Equipment failures typically take much longer to repair when the sensor is owned by the facility. You have to wait on their personnel, who may not see it as high a priority as your own technicians. At several sites, we have lost signals for many months because we had to wait until the facility's maintenance staff could repair the problem.

Other Instrumentation

Anemometers will routinely fail to perform after six months of operation. In one project, weather data were collected at several sites across Texas. The weather stations included temperature, relative humidity, solar radiation, and wind speed. Besides relative humidity sensor problems, which have been documented previously (O'Neal et al 1993), anemometers were a problem. Wind anemometers functioned fine for the first few months. However, moisture and contaminants would eventually affect the bearings and the output from the transducer. Because the data were of limited value (i.e., the only use is for creating a weather tape for a simulation program) and the maintenance costs so high, wind measurements were abandoned.

EQUIPMENT INSTALLATION

While the above section dealt more with characteristics of the instrumentation out of the box, many problems associated with instrumentation focus on their application (or misapplication). Some problems discovered during the installation of instrumentation are listed below. The same order is followed as before. Thermal metering is discussed first, followed by electrical instrumentation and psychrometric instrumentation.

Thermal Metering

Problems with the installation of thermal metering includes the temperature and flow inputs to the thermal energy meter as well as the thermal energy meter itself.

1. No optimal location will be available for a flowmeter installation. Both insertion and fixed type flowmeters require a number of diameters of

straight pipe both before and after the flowmeter to provide an accurate reading. However, in many facilities, it is difficult to provide more than 2 to 8 diameters of straight pipe upstream of the flowmeter. Unfortunately, such small lengths of straight pipe can affect the flow measurement by as much as 15 to 20% (Parker and O'Neal 1993, Bryant and O'Neal 1996).

2. The mechanical contractor installing the flowmeter hot-tap locations will chose the worst location. Unless the flow metering locations are physically marked on the pipe and the engineer is there when the contractor is doing the work, it is almost certain to be done incorrectly. At a free-cooling retrofit location in west Texas, the flowmeter was installed at a location one diameter downstream of two out-of-plane 90° elbows. What made this so ironic was that upstream of the elbows was 30 diameters of straight 6" pipe. In another instance, the contractor had already marked the piping where he was going to do the hot-tap. Unfortunately, the hot-tap was in a section of the piping which would have only measured a part of the chilled water flow. Fortunately, the metering engineer was visiting the site that day and was able to correct the problem.

3. Installation of a flowmeter on the primary loop will provide more grief than one on the secondary side of the system. Our experience with thermal monitoring on the primary loop is that the velocities in the piping on the primary side are often much lower than the secondary side. Unfortunately, the velocities are sometimes low enough on the primary side that they are below the minimum operating threshold of the flowmeter. This has required installing new equipment on the secondary side to be able to accurately measure the thermal energy.

4. Trying to save money by using existing thermal metering will most likely cost more money than installing new equipment. Because many facilities have an existing EMCS, it is very tempting to use some of the existing thermal metering. It is often a straightforward process to split a signal from an existing thermal energy meter or pressure transmitter and share the meter with the energy monitoring hardware. In our experience, there is an up-front hardware savings by using existing equipment, but this is more than offset by the maintenance and diagnostic cost of trying to determine why some of the existing equipment doesn't work. In one facility, we used the existing flowmeters, which were average pitot tube type with differential pressure transmitters. Approximately 10% of the transmitters did not produce an output and another 15% were out of calibration. Figure 1 shows an example of a 0 to 10 inH_20 transmitter whose calibration was tested. While its output should have been linear over the whole range of pressures, it was began to deviate at 3 inH_2O and had a maximum output of approximately 12 milliamps compared to the expected 20. In addition, some of the existing flowmeters were installed near elbows and tees and could not be expected to provide accurate readings.

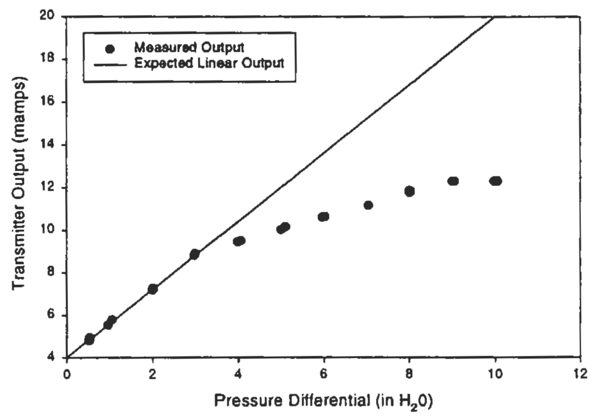

Figure 1 – Output from a pressure differential transmitter that was on an existing facility flowmeter.

5. Asbestos insulation will be on the piping where the thermal metering instrumentation needs to be installed. Unfortunately, asbestos is one of the hazards encountered in thermal metering in buildings. For buildings constructed before 1970, asbestos can be expected to be used in some of the piping insulation. Asbestos abatement can drive the cost of thermal metering so high that it can endanger the installation. In at least one building, we did not install any thermal monitoring because all the piping had asbestos insulation on it. "Is there asbestos on the chilled or hot water piping?" should be one of the first questions an engineer asks of the facilities or building manager before going to the trouble of developing an instrumentation plan. The next logical question to ask is: "who is going to pay for the abatement of the asbestos?"

6. The diameter of the pipe in which the flowmeter is installed will be different from that indicated by the facility manager or shown on the building schematics. With many insertion flowmeters, the pipe size is a critical piece of information for both installing the flowmeter at the right depth in the pipe and setting the thermal meter correctly. If the pipe diameter is incorrect, then the pipe thickness is also incorrect, which means the insertion depth of the flowmeter will be incorrect and if the incorrect constant is entered into the BTU meter, the BTU reading will also be incorrect. While building operators or building schematics (which may not reflect the as-built condition) are useful, the only diameter for the pipe that should be trusted is the one which is directly measured. At one site, the information provided on five different pipes (out of five) was incorrect.

7. If a temperature probe can be reached by a person from the floor, the probe will be used as a climbing aid. A continuing problem with chilled and hot water temperature probes is their destruction by facility or repair personnel as an aide when climbing on top of the piping system. A number of probes have been broken off or bent as much as 90 degrees. If the temperature sensor breaks, the result is a bad reading for the thermal energy, which must be diagnosed with a trip to the site. An example of this problem is shown in Figure 2. Here, an insulation contractor used the sensor to reach some overhead piping. Though severely bent, the thermistor still functioned. Unfortunately, we have seen installations where not only our temperature probes have been abused in this way, but also those of an EMCS contractor.

8. If a thermal energy meter is no longer functioning, it will be because the temperature sensor(s) no longer exists. On some of our first installations, the compression fitting used for the insertion of RTDs into a pipe allowed the RTD probes to vibrate within the pipe. The vibrations eventually produced a fatigue failure of the probe where it protruded from the compression fitting into the flow stream. The probes broke off and disappeared into the pipe. While thermowells would be one solution to using immersion temperature probe, the cost for hot tapping a thermowell is much higher than that for a probe. On other installations, the retrofit contractor removed sections of pipe containing the flow meter and temperature sensors that were part of the thermal metering. While it may not be possible to completely eliminate this problem, careful coordination and placement of the metering equipment can minimize its occurrence.

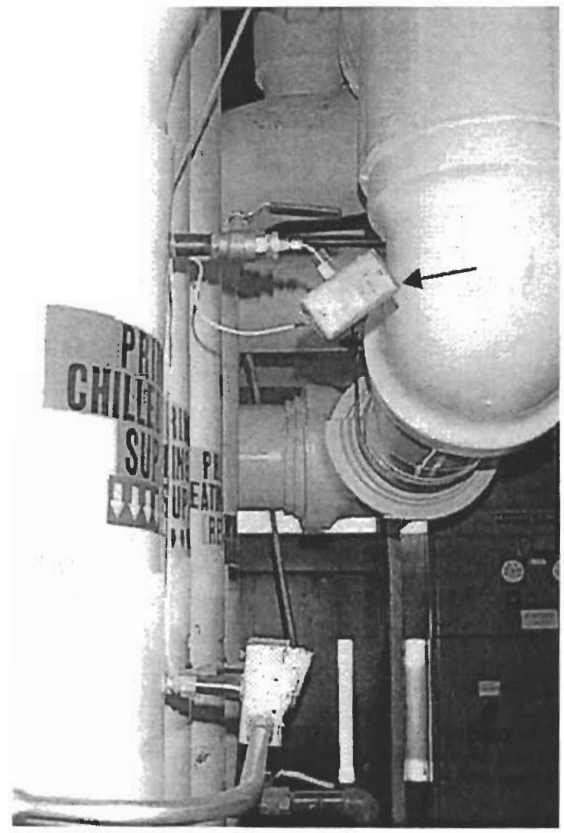

Figure 2. Result of using a thermistor (top) as a ladder.

1. The boiler feedwater temperature will exceed the temperature rating of the flow meter. The meters typically used to measure condensate return and boiler feedwater have an upper temperature limit of 25O°F. These meters have worked satisfactorily at several sites under these conditions. However, there have been problems when steam has passed through the meter and melted the meter's internal parts. A significantly more expensive strain gage target meter with stainless steel parts has been used to replace meters with this problem.

Electrical Metering

There have been several problems with the installation of electrical metering equipment. In many cases, the problems could have been avoided if the installing electrician had been properly supervised.

1. If multiple transformer feeds are available in the building, then the potential transducer will be connected to the wrong reference voltage. One of the data loggers we use can accept two different potential transducer references. These are used for CT references and the proper internal calculation of active power. A common field error is referencing CTs to the wrong PT or referencing all CTs in a building to a single PT when there are several transformers (requiring several PTs) in the building. The most extreme case involved a large 12 story office building which had 4 different transformers in the building. Only one PT was installed and used as a reference for all the CTs in the building. Several costly fixes were necessary to correct the problem and several months worth of pre-retrofit data were lost because of the problem.

2. If a current transformer is installed on an existing CT secondary, they will not be scaled properly. On large electrical loads (i.e. main building feed, centrifugal chiller feed) there often are existing current transformers available. These existing CTs are used by building operations personnel to monitor the electrical loads at these devices. For example, a large centrifugal chiller might have CTs with 1000 to 5 ratios on each of the 3 phases to the chiller motor. The ratio indicates that the CT will output 5 amps if the motor is loaded at 1000 amps. The monitoring technique consists of installing a second 5 amp CT on the existing CT secondary wire. The CT ratio of the primary and the secondary CT is then necessary to calculate the final CT ratio. This ratio is used to properly scale (through the data logger software) the signal received at the data logger. In some installations, the primary CT ratio was not determined and the ratio was estimated. Only after the existing CT ratio is properly determined and field verified, can the signal be trusted.

3. The standard convention of phasing of power in electrical cabinets will not be followed. Electricians often use a standard set of rules for installing the A, B, and C phases of three phase equipment. These three phases should go (as you face the electrical connection) left-to-right (A, B, C), up-to-down (A, B, C), or front-back (A, B, C), depending on the cabinet style. We have encountered several installations where the phasing was different than standard convention and no notice was left by the electrician to indicate the unusual phasing convention.

Other Instrumentation

1. The data logger will probably be programmed incorrectly when data collection starts. The data loggers used can have from 14 to 47 data channels connected. While care is taken to program the data loggers correctly when the site is first brought on line, loggers have had to be carefully checked channel by channel to ensure that what is recorded in the documentation is what was programmed into the logger by the field engineer.

1. You can never schedule enough lead time for coordinating the installation of pulse initiators with the local utility company. Coordination efforts with local electrical (or gas) utilities can vary. In most cases, the local utility is knowledgeable and responsive to requests for installation of pulse initiating equipment or splitting signals from existing equipment. it is best to allow or accept 3 months lead time, know what equipment is necessary, know exactly where and when you need it, and to verify that the scales given by the utility are correct. In addition, some electrical metering pulse initiators have an electronic relay which, by itself, may not be compatible with data acquisition systems. In those cases, an additional isolation relay is necessary to eliminate the resistance when the relay closes.

EQUIPMENT MAINTENANCE

Once the instrumentation is in place, it must be maintained. The maintenance may be more difficult to handle than the original installation. When instrument fails, it requires a trip to the site to diagnose the problem and at least one or more subsequent trips to the site to fix the problem. The cost of maintenance will probably exceed the initial expectations of personnel on the project. The types of failures seen in the field will depend on the type of instrumentation used. The rule of thumb is to expect all instrumentation to fail at some point in the program. In two years, the types of maintenance problems and failures seen thus far include:

1. Modem failure. While the trend in the past year has been for direct connection of data loggers to the internet at those sites with ethernet cabling already installed, modems are still used in many installations. Modems can represent a significant maintenance cost. While the number of modem

failures is not large, the failure of one modem can potentially disrupt the data collection for two to three buildings when the buildings are monitored by a single logger. One particularly annoying failure of the modem occurs after a short power outage. The modem will not properly reset and will not answer when called. In such a case, the logger cannot be reached remotely via the phone. The modem has to be turned off and then back on to properly reset the modem. Because some of the buildings are hundreds of miles from the ESL, doing this more than once can be very time consuming and costly.

2. Metering equipment disconnected or damaged - One of the uses of our energy metering equipment is to monitor a site before and after an energy conservation retrofit. As shown in Figure 3, our equipment is clearly labeled with large fluorescent orange stickers with information about calling our office collect before disconnecting or removing the equipment. In spite of the stickers, we continue to have problems with contractors removing or damaging hardware. The damage is not evident until the data logger has been polled. The cause of the problems have to be diagnosed with a site visit. At one site, it was found that an electrical subcontractor had disconnected the wiring for both reference voltage and CT inputs to the data logger. At another site, an asbestos abatement contractor tore the wires from a pressure transducer and caused a short to the data logger which damaged the logger's analog circuiting. The problem caused the loss of several weeks building energy data. In another instance, an EMCS contractor stole our whole building electric signal by disconnecting the wires from our data logger and connecting it to their EMCS. Another contractor installing a chiller disconnected our CTs from the electrical panel and apparently discarded them or took them. These problems still persist, even though measures have been taken to ensure that the facilities' personnel and their contractors are made aware that our metering instrumentation is installed in their buildings and that we should be notified before it is disturbed.

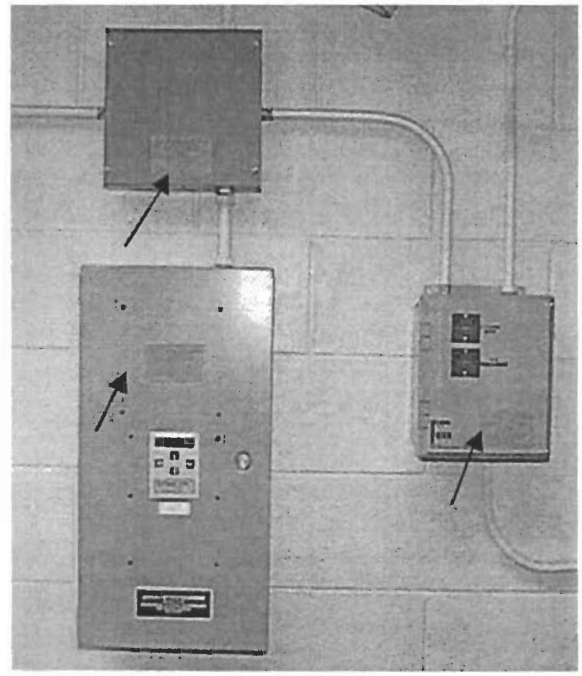

Figure 3. Just because it is marked well...(Note: arrows added for emphasis.)

3. Current transformer failure - There have been several instances of the shunt resistor failing in the CT. This allows the CT to output a voltage far higher than the 333 mVac at rated load. In one case, the CT was outputting 10 VAC which caused the logger to record false power readings for the affected channel as well as other channels. One other site had a similar problem and provided over 50 volts to the logger.

4. DAS Main Processor Boards - These boards contain a significant number of electronic components and many can fail. Although these component failures (such as capacitor, internal power supply, diode, and CPU, etc.) were relatively few during the first 18 months of one project, the number has significantly increased during the subsequent 18 months. the DAS equipment still seems to be acceptable in terms of dependence and the manufacturer has been reasonable, fair and prompt in completing the repairs. The reason for the number of failures may be due to the typically harsh conditions in which the DAS is used. To minimize field trips to diagnose and repair DAS failures, it is recommended that a spare main processor board be taken to a site whenever a failure is suspected.

Because the type of equipment used in this project is very interchangeable, as few as 2 or 3 spare processor boards has been adequate and has saved many distant return trips.

5. Flow meter components - For the most part, the flow meter electronic and mechanical components in the chilled and hot water systems have been very dependable. One brand which was used several years ago had an electronics package in the flow meter which failed several times. Another problem was the existence of metallic debris in the pipe. This became apparent during the installation of another type of insertion flow meter. The trash struck the impeller of the flow meter, causing the impeller to be destroyed. In another case, a flow meter which had been installed near the bottom of a pipe was being extracted for regular service and miscellaneous trash had accumulated in the plumbing fittings. The accumulation would not allow a valve to close completely which prevented the removal of the meter.

6. Interruption of gas metering - Certain types of electronic gas metering equipment require a battery to power the electronics in the meter. When the battery goes dead, the meter loses its memory and stops recording consumption data. If the utility company and/or facility does not share the signal, they probably will not notice the problem and will not make an effort to replace the battery until you notice the problem and call them. The meter will also need to be reprogrammed when the battery is replaced. This sounds simple, but be prepared for numerous telephone conversations with the utility company as well as the facility which can take weeks or months to complete.

7. Phone system problems - Discontinuation of service, reprogramming of the campus network, wiring failure, and area code changes are a few of the problems with phone service that have occurred. Sometimes the facility forgets why there is a phone line connected to the data acquisition system. In these instances, they have eliminated the phone line without contacting us. These problems have happened on a recurring basis. When a communications line failure happens, the natural cause is thought to be a modem failure. The loss of the communication line is reported to the appropriate facility contact and then the wait begins. It has taken as long as three months to restore service. This amount of time is not unusual for the original installation of service, either. However, retrieving the data must be accomplished manually on site when the phone is dead. In some instances this requires a field trip every few weeks to avoid loss of data because the loggers begin overwriting their memory. Wiring failures usually occur due to the use of 24 gauge solid copper wire which is somewhat brittle and can be damaged or broken easily in long runs or at termination points. Another simple problem that occurs with phone systems is an area code change. In many instances, the facility does not contact us about the area code change. An area code change can mimic a disconnected phone line because the message is the same on the phone line. Usually, a call to the facilities manager solves the problem.

SUMMARY AND CONCLUSIONS

There are two things which have helped to ensure that the data collected are of good and consistent quality: 1) Only reliable contractors must be used and 2) The experience has been gained "in-house" to perform basic troubleshooting diagnostics and take corrective actions. Another helpful development has been provided by the programming and analysis group. After the data has been downloaded from the data loggers, it is sent through a number of data reduction routines and checked weekly for missing data, power outages, or other data stream problems (Haberl, et al., 1990). After this process, the data are graphed and the finished graphs inserted in a project binder which contains approximately six weeks of graphed data. This binder is circulated to several of the engineers and analysts involved in the group. If there are instrumentation problems in the field, they are most often identified through the inspection of these weekly graphs. If a plot of a particular data channel has some questionable trends, the problem is cited and passed on to the field engineer for investigation. A formal procedure has been developed to track any data related problem from identification through corrective action taken. Though it sounds as though there has been nothing but problems on this project, it is felt that the majority of the installations have gone in with little or no trouble. The "war stories" cited in this paper are examples of the types of problems which have been encountered. The intent has been to present them openly so that others involved in building energy metering projects may benefit from the experiences and avoid similar pitfalls.

REFERENCES

Bryant, J., and O'Neal, D., 1996. "Effects of a 90 Degree Elbow on the Accuracy of an Insertion Paddle-Wheel Flow Meter, Comparison for 0.1 and 0.15m Diameter PVC Pipe," *Proceedings of the Tenth Symposium on Improving Buildings in Hot and Humid Climates*, Texas A&M University, College Station, Texas, May.

Haberl, J., Katipamula, S., Willis, D., Weber, K., Matson J., Rayaprolu, M., Subramanian, U. 1990. "The Texas LoanSTAR Program: Acquiring and Archiving LoanSTAR Data", *Proceeding of the Seventh Annual Symposium on Improving Building Systems in Hot and Humid Climates*, Texas A&M University, College Station, Texas, October.

Nutter, D., Britton, A., Muraya, N., Heffington, W. 1990. "LoanSTAR Energy Conservation Audits: January 1989 - August 1990", *Proceeding of the Seventh Annual Symposium on Improving Building Systems in Hot and Humid Climates*, Texas A&M University, College Station, Texas, October.

O'Neal, D., Bryant, J., Turner, D., Glass, M. 1990. "Metering and Calibration in LoanSTAR Buildings", *Proceeding of the Seventh Annual Symposium on Improving Building Systems in Hot and Humid Climates*, Texas A&M University, College Station Texas, October.

O'Neal, D., Bryant J., and Boles, K., 1992. "Building Energy Instrumentation for Determining Retrofit Savings: Lessons Learned, " *Solar Engineering 1992*, Proceedings of the ASME/JSES/KSES International Solar Energy Conference, Maui, Hawaii, April.

O'Neal, D.L., Bryant, J., Boecker, C., and Bohmer, C., 1993. "Building Energy Instrumentation for Determining Retrofit Savings: Murphy's Law Revisited", *Proceedings of the 15th Industrial Energy Technology Conference*, Houston, Texas, March.

Parker, B. and O'Neal, D., 1995, "Effect of Ninety Degree Elbow on the Accuracy of a Non-Magnetic, Insertion Paddle Wheel Flowmeter", *Solar Engineering 1995*, Proceedings of the ASME/JSME International Solar Energy Conference, pp. 731-740, Maui, Hawaii, March.